O'Connor, president of AES NewEnergy's Chicago office. "You cannot have competition being viable when your base of potential customers is so small."

Arlene Juracek, ComEd vice-president of regulatory and strategic services, counters that few businesses actually will pay higher rates in the short term because the rise in delivery charges will be offset in many cases by a corresponding decrease in "transition" fees paid to the utility when customers use another supplier.

The Aug. 31 transmission rate proposal, filed with the Federal Energy Regulatory Commission (FERC), surprised the Illinois Commerce Commission, which asked FERC two weeks ago to block the rate hike.

The latest rate hike proposal incorporates a proposed change in ComEd's account methodology, in which the utility would wipe off its books more than $660 million of accumulated depreciation of transmission assets and ask ratepayers to shoulder that investment again.

'Unjust and unreasonable'

In its filing with FERC, the ICC said the proposed change "would result in artificially high transmission rates, and an unjust and unreasonable windfall to ComEd at the expense of transmission ratepayers."

"They're essentially changing the rules of the game halfway through the game," says ICC Commissioner Terry Harvill.

ComEd responds that FERC itself — in an order last year pushing utilities to combine their transmission assets into large, regional networks — said utilities could consider changing the accounting method.

"ComEd believes we have an obligation to the shareholders of (parent company) Exelon Corp. to receive compensation in accordance with what is permissible by law," says Steven T. Naumann, ComEd vice-president in charge of transmission services. "The commission will determine if this is what they meant (in their order) or if it is not what they meant."

Meanwhile, the city of Chicago, frustrated by ComEd's resistance to sharing detailed financial data, is poised ask the ICC formally to order an outside audit of ComEd's books for 2000. The state attorney general's office and the Cook County state's attorney's office are joining the city in the petition, which could be filed as early as Monday, sources say.

The audit, which ComEd opposes, would be aimed at separating ordinary maintenance and improvement costs from the extraordinary measures ComEd took in 1999 and 2000 to beef up its distribution system, after acknowledging it had neglected that infrastructure during the previous two decades.

The behind-the-scenes skirmishing spotlights how seriously local government officials are taking the regulatory proceedings. While the new rates affect only those customers in the competitive market, they'll be the benchmark used for the power delivery charges all other ComEd customers will pay in 2005, when the utility's "bundled" rates are no longer frozen.

Setting the rules

"The company is very much aware of the fact that the rules for the future are getting set now," says William Abolt, commissioner of the city's Department of Environment. "Basically, the next 36 months are going to set an awful lot of the fees for the future."

Mr. Abolt says the audit request is one option the city has to pressure ComEd into opening its books, but says it wouldn't be necessary if the company agreed to do so voluntarily.

A ComEd executive says the data will be made available to those who sign a blanket confidentiality agreement — which intervenors in the case, including the city, aren't likely to sign.

Ms. Juracek of ComEd says the utility already has sifted extraordinary costs associated with its $1.5-billion infrastructure upgrade out of the rate base. But she allows that most of those are minimal tree-trimming expenses. Large amounts of overtime paid to unionized workers, as well as contractor expenses, are included in the rates.

"There's no free lunch here," she says.

Says Mr. Abolt: "Now, it's time to sort that all out. So, let's sort it out."

B

Appendix B

Transmission Rates

The transmission rate figure of 0.409¢ per kWh that was used in this customer impact analysis is based on Edison's response to ARES Coalition Data Request 8.01 where Edison stated that "the $342,224,429 proposed annual transmission service revenue requirement is comparable to the $169,800,000 revenue requirement." The Annual Transmission Requirement amount of $342,224,429 is from Exhibit No. CEC-300 (Statement BK, Schedule 1, Page 1, Line 21, Column d) of the Direct Testimony of Alan C. Heintz filed with FERC on August 31, 2001, at Docket No. ER01-2992-000.

The *Annual Ancillary Transmission Revenue Requirement* is derived by: (a) taking the Total Annual Revenue for Ancillary Services Requirement amount of $55,701,303 from Edison Exhibit 13.0 (Attachment E, Page 1 of 4) of the Panel Direct Testimony of Lawrence S. Alongi and Sharon M. Kelly, P.E. filed with the Commission on June 1, 2001 in the instant proceeding; (b) subtracting the amount of $16,126,306 for Scheduling, System Control and Dispatch Services (Scheduling) reflected on that same page of Edison Exhibit 13.0; and (c) adding the revised amount of $20,410,594 for Scheduling from Exhibit No. CEC-300 (Statement BK, Schedule 1, Page 1, Line 21, Column e) of the Direct Testimony of Alan C. Heintz filed with FERC on August 31, 2001, in Docket No. ER01-2992-000 ($55,701,303 - $16,126,306 + $20,410,594 = $59,985,591).

The Annual Retail Customers Load Ratio Share of 88.05% and the Annual Energy Sales for Retail Customers amount of 86,488,165,896 kWh are from Edison Exhibit 13.0 (Attachment E, Page 2 of 4, Columns C and H, respectively) of the Panel Direct Testimony of Lawrence S. Alongi and Sharon M. Kelly, P.E. filed with the Commission on June 1, 2001 in the instant proceeding. These Revenue Requirement figures were substituted for those shown in Edison's Exhibit 13.0 E, page 2 of 4 to arrive at the 0.409¢ per kWh shown in Table 2.

Cases #1 and #2 both use the 0.409¢ per kWh transmission cost figure while Case #3 uses current Edison transmission charges.

Distribution Rates

The Delivery Service Charges used in Case #1 to provide Edison with its full revenue requirement without incorporating the HVDS discount or the 12-month ratchet rate design were derived simply by multiplying the current RCDS fixed monthly charges and demand charges for distribution by the 36.7% shown and described in Table 2.

For purposes of Cases #2 and #3, we assumed that GCI witness Effron will propose a $169M increase in Edison's revenue requirement. This is based on an anticipated net revenue requirement of about $1.38B which is about $169M higher than Edison's current delivery services revenue requirement of $1.211B approved in Docket 99-0117. This compares to Edison's request of an increase of $575M in this proceeding.

The Delivery Service Charges used in Cases #1 and #2 to provide Edison with the revenue requirement identified by Mr. Effron without incorporating the HVDS discount or the 12-month ratchet rate design were derived simply by multiplying the current RCDS fixed monthly charges and demand charges for distribution by the 5.6% shown and described in Table 2.

In all cases, the appropriate adjustments were made to the CTC's (whether Class determined or Custom determined) for each of the customer accounts under examination.

C

Table 1: Comparison of Current and Proposed Revenue Requirements (millions)										
Revenue Level and Case [#]	Transmission (T)	Ancillary (A)	Distribution (D) Revenue Requirement	$ Increase in Distribution (D) Revenues	$ Increase in Transmission & Ancillary Revenues (T+A)	$ Increase in Total Wires (D+T+A) Revenues	% Increase in Distribution (D) Revenues	% Increase in Transmission & Ancillary Revenues (T+A)	% Increase in Total Wires (D+T+A) Revenues	Required % Increase in Distribution *Rates*
Current Revenue Levels	169.8 a/	55.7 a/	1,211.0 d/							
Revenue Levels in CE Direct Testimony	169.8 a/	55.7 a/	1,786.0 e/	575.0	0.0	575.0	47.5%	0.0%	40.0%	36.7% g/
Revenue Levels in CE Direct Testimony & Transmission from FERC Filing - Case [1]	342.2 b/	60.0 c/	1,786.0	575.0	176.7	751.7	47.5%	78.4%	52.3%	36.7% g/
Revenue Levels in Effron Rebuttal Testimony & Transmission from FERC Filing - Case [2]	342.2 b/	60.0 c/	1,380.0	169.0 f/	176.7	345.7	14.0%	78.4%	24.1%	5.6% h/
Revenue Levels in Effron Rebuttal Testimony & Current Transmission Costs - Case [3]	169.8 a/	55.7 a/	1,380.0	169.0 f/	0.0	169.0	14.0%	0.0%	11.8%	5.6% h/

Source: a/ ComEd's Panel Testimony of Lawrence S. Alongi and Sharon M. Kelly, P.E. filed with the ICC on June 1, 2001, at Docket No. 01-0423 (ComEd Exhibit 13.0, Attachment E, Page 1).

b/ ComEd's Direct Testimony of Alan C. Heintz filed with the FERC on August 31, 2001, at Docket No. ER01-2992-000 (Exhibit No. CEC-300, Statement BK, Schedule 1, Page 1, Line 21, Column d).

c/ This amount is derived by: (a) taking the Total Annual Revenue for Ancillary Services Requirement amount of $55,701,303 from ComEd Exhibit 13.0 (Attachment E, Page 1 of 4) of the Panel Testimony of Lawrence S. Alongi and Sharon M. Kelly, P.E. filed with the ICC on June 1, 2001, at Docket No. 01-0423; (b) subtracting the amount of $16,126,306 for Scheduling, System Control and Dispatch Services (Scheduling) reflected on that same page of ComEd Exhibit 13.0; and (c) adding the revised amount of $20,410,594 for Scheduling from Exhibit No. CEC-300 (Statement BK, Schedule 1, Page 1, Line 21, Column e) of the Direct Testimony of Alan C. Heintz filed with FERC on August 31, 2001, at Docket No. ER01-2992-000. ($55,701,303 - $16,126,306 + $20,410,594 = $59,985,591)

d/ Per the ICC Order on Rehearing issued March 9, 2000, at Docket No. 99-0117 (Appendix A, Schedule 1, Column H, Line 1).

e/ ComEd's Direct Testimony of Jerome P. Hill filed with the ICC on June 1, 2001, at Docket No. 01-0423 (ComEd Exhibit 4.0, Appendix C, Schedule A-2 (AD-004), Page 1, Line 7).

f/ For purposes of this analysis we have assumed that GCI witness David Effron will produce a $169.0M revenue requirement increase.

g/ This amount is derived by: (a) subtracting ComEd's current Average Delivery Revenue Requirement Rate of $.0150/kWh from its proposed Average Delivery Revenue Requirement Rate of $.0205/kWh; and (b) dividing the difference by ComEd's current Average Delivery Revenue Requirement Rate ($.0150/kWh). [$0.0205 - $0.0150 = $.0055 and $.0055 / $.0150 = 36.7%] The proposed and current Average Delivery Revenue Requirement Rates of $.0205 and $.0150 are from the Direct Testimony of Arlene A. Juracek, P.E. *filed on June 1, 2001, at Docket No. 01-0423. (Page 20 of 26, Lines 514 and 517, respectively)*

h/ The required percent increase in distribution rates is equal to D or 5.6%.

Whereas:
A = Ratio of total proposed revenue requirement to the proposed rate requirement (1.786 / 2.05 = 0.8712)
B = Ratio of total current revenue requirement to the current rate requirement (1.211 / 1.50 = 0.8073)
C = Distribution revenue requirement (per Effron's Rebuttal Testimony) divided by A (1.380 /0.8712 = 1.584)
D = The quotient of (C divided by current rate requirement) minus 1 [(1.584 / 1.50) -1 = 5.6%]

Table 2: Transmission Cost Comparison

RCDS Class #	Current PPO Transmission Charges	Transmission Charges Used by ComEd in this Proceeding	Difference from current PPO Transmission Charges	Estimated Transmission Charges based on recent FERC Filing*	Difference from current PPO Transmission Charges	
1	0.289	0.230	0.059	0.409	0.120	¢/kWh
2	0.344	0.230	0.114	0.409	0.065	¢/kWh
3	0.343	0.230	0.113	0.409	0.066	¢/kWh
4	0.320	0.230	0.090	0.409	0.089	¢/kWh
5	0.295	0.230	0.065	0.409	0.114	¢/kWh
6	0.292	0.230	0.062	0.409	0.117	¢/kWh
7	0.272	0.230	0.042	0.409	0.137	¢/kWh
8	0.267	0.230	0.037	0.409	0.142	¢/kWh
9	0.260	0.230	0.030	0.409	0.149	¢/kWh
10	0.228	0.230	(0.002)	0.409	0.181	¢/kWh

*: see appendix of Rebuttal Testimony for derviation

TABLE 3 CONTAINS CONFIDENTIAL INFORMATION

Table 4: Comparison of PPO Market Values to Rider ISS Market Values for Period A

Schedule 1: PPO Period A Market Values (06/01 - 05/02) for RCDS Classes 1-10*[1]

		Summer MVEC's - A			Non-Summer MVEC's - A		
Class #	Class	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)
1	Wh only			**7.849**			**4.072**
2	0-25 kW			**7.422**			**3.929**
3	25-100 kW			**7.276**			**3.935**
4	100-400 kW			**7.154**			**3.873**
5	400-800 kW	11.371	2.990	**6.849**	4.789	2.944	**3.784**
6	800-1,000 kW	11.271	3.060	**7.010**	4.784	2.977	**3.837**
7	1,000-3,000 kW	11.129	2.891	**6.538**	4.722	2.900	**3.698**
8	3,000-6,000 kW	11.117	2.844	**6.431**	4.721	2.889	**3.672**
9	6,000-10,000 kW	11.036	2.796	**6.260**	4.720	2.869	**3.634**
10	Over 10,000 kW	10.839	2.764	**6.205**	4.618	2.785	**3.569**

*1: From Attachment A - ComEd Rider PPO, April 20, 2001.

Schedule 2: Rate Difference Between Rider ISS and PPO Period A Market Values*[2]

		Summer MVEC's - A			Non-Summer MVEC's - A		
Class #	Class	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)
1	Wh only			-2.610			-0.152
2	0-25 kW			-1.809			-0.072
3	25-100 kW			-2.267			-0.072
4	100-400 kW			-1.776			-0.069
5	400-800 kW	-2.641	-1.152	-2.034	0.195	-0.241	-0.038
6	800-1,000 kW	-2.471	-0.912	-1.927	0.190	-0.261	-0.068
7	1,000-3,000 kW	-2.223	-0.977	-1.586	0.202	-0.219	-0.028
8	3,000-6,000 kW	-2.271	-0.997	-1.503	0.189	-0.211	-0.034
9	6,000-10,000 kW	-2.032	-0.956	-1.551	0.198	-0.207	-0.034
10	Over 10,000 kW	-1.755	-0.882	-1.300	0.222	-0.174	-0.024

*2: From ComEd Response to ARES Coalition Data Request, 9/27/01, AC 0001076.

Schedule 3: Derived Period A Rider ISS Market Values*[3]

		Summer MVEC's - A			Non-Summer MVEC's - A		
Class #	Class	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)
1	Wh only			5.239			3.920
2	0-25 kW			5.613			3.857
3	25-100 kW			5.009			3.863
4	100-400 kW			5.378			3.804
5	400-800 kW	8.730	1.838	4.815	4.984	2.703	3.746
6	800-1,000 kW	8.800	2.148	5.083	4.974	2.716	3.769
7	1,000-3,000 kW	8.906	1.914	4.952	4.924	2.681	3.670
8	3,000-6,000 kW	8.846	1.847	4.928	4.910	2.678	3.638
9	6,000-10,000 kW	9.004	1.840	4.709	4.918	2.662	3.600
10	Over 10,000 kW	9.084	1.882	4.905	4.840	2.611	3.545

*3: Derived by Subtracting the Market Values in Schedule 2 from Schedule 1.

Schedule 4: % Difference Beetween Rider ISS and PPO Period A Market Values*[4]

		Summer MVEC's - A			Non-Summer MVEC's - A		
Class #	Class	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)	On-Peak (¢/kWh)	Off-Peak (¢/kWh)	Non-TOU (¢/kWh)
1	Wh only			-33.3%			-3.7%
2	0-25 kW			-24.4%			-1.8%
3	25-100 kW			-31.2%			-1.8%
4	100-400 kW			-24.8%			-1.8%
5	400-800 kW	-23.2%	-38.5%	-29.7%	4.1%	-8.2%	-1.0%
6	800-1,000 kW	-21.9%	-29.8%	-27.5%	4.0%	-8.8%	-1.8%
7	1,000-3,000 kW	-20.0%	-33.8%	-24.3%	4.3%	-7.6%	-0.8%
8	3,000-6,000 kW	-20.4%	-35.1%	-23.4%	4.0%	-7.3%	-0.9%
9	6,000-10,000 kW	-18.4%	-34.2%	-24.8%	4.2%	-7.2%	-0.9%
10	Over 10,000 kW	-16.2%	-31.9%	-21.0%	4.8%	-6.2%	-0.7%

*4: Percentage Difference Between Schedule 1 and Schedule 3.

Case 1: Comparison of Current PPO Components to Proposed PPO Components for Selected Customer Accounts (DSTs based on Current Rate Design & Full Revenue Requirement. Transmission Costs based on FERC Filing.)

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$189	$20	($186)	($8)	$15	Yes	No
3A	$1,159	$57	($449)	($33)	$734	Yes	No
3B	$695	$65	($511)	($38)	$212	Yes	No
3C	$1,081	$157	($1,240)	($91)	($92)	No	No
3D-IRMA	$1,191	$226	$0	($131)	$1,286	Yes	No
3E-IRMA	$676	$179	$0	($102)	$752	Yes	Yes
3F	$1,062	$311	($2,455)	($180)	($1,262)	No	No
4A	$998	$127	($587)	($24)	$514	Yes	No
4B	$2,190	$321	($1,482)	($60)	$969	Yes	No
4C	$5,208	$1,119	($5,163)	($208)	$956	Yes	No
4D	$1,818	$535	($2,471)	($99)	($217)	No	No
4E	$2,761	$1,029	($4,750)	($194)	($1,154)	No	No
5B	$6,456	$1,082	($1,824)	($338)	$5,376	Yes	No
5C	$7,205	$1,875	($3,161)	($554)	$5,365	Yes	No
5D	$10,356	$4,086	($6,888)	($1,162)	$6,391	Yes	No
5E	$9,000	$4,117	($6,940)	($1,096)	$5,080	Yes	Yes
5F	$10,308	$4,923	($8,300)	($1,331)	$5,600	Yes	Yes
6B	$9,352	$2,359	($2,891)	($297)	$8,523	Yes	No
6C	$10,690	$3,787	($4,642)	($567)	$9,268	Yes	No
6D	$12,171	$4,284	($5,252)	($595)	$10,608	Yes	No
6E	$13,239	$6,907	($8,466)	($945)	$10,734	Yes	Yes
7B	$19,707	$3,668	($3,815)	($640)	$18,920	Yes	No
7C	$24,737	$9,347	($9,723)	($1,726)	$22,635	Yes	No
7D	$24,869	$12,684	($13,194)	($2,105)	$22,254	Yes	No
7E	$43,139	$22,900	($23,821)	($3,751)	$38,467	Yes	No
7F	$17,338	$10,032	($10,436)	($1,485)	$15,450	Yes	Yes
8C	$51,295	$20,278	$0	($2,342)	$69,231	Yes	No
8D	$70,011	$33,817	$0	($3,780)	$100,048	Yes	No
8E	$77,743	$45,960	$0	($5,057)	$118,645	Yes	Yes
8F	$67,523	$43,962	$0	($4,787)	$106,699	Yes	Yes
9C	$92,255	$43,816	$0	($4,742)	$131,329	Yes	No
9D	$79,940	$42,433	($30,943)	($4,842)	$86,587	Yes	No
9E	$118,114	$66,657	($58,865)	($7,284)	$118,622	Yes	No
10B	$107,076	$97,107	($3,478)	($8,765)	$191,940	Yes	No
10D	$105,490	$112,677	$0	($9,556)	$208,612	Yes	No
10E	$87,276	$123,409	($17,001)	($10,095)	$183,589	Yes	No
SH-B	$787	$70	$0	($41)	$816	Yes	No
SH-C	$2,638	$472	$0	($89)	$3,021	Yes	No
SH-D	$5,302	$1,564	$0	($291)	$6,575	Yes	Yes
HV-E	$161,097	$189,893	$0	($15,664)	$335,326	Yes	Yes
HV-F	$115,033	$77,177	$0	($7,490)	$184,720	Yes	Yes

Case 2: Comparison of Current PPO Components to Proposed PPO Components for Selected Customer Accounts (DSTs based on Current Rate Design & Effron Revenue Requirement. Transmission Costs based on FERC Filing.)

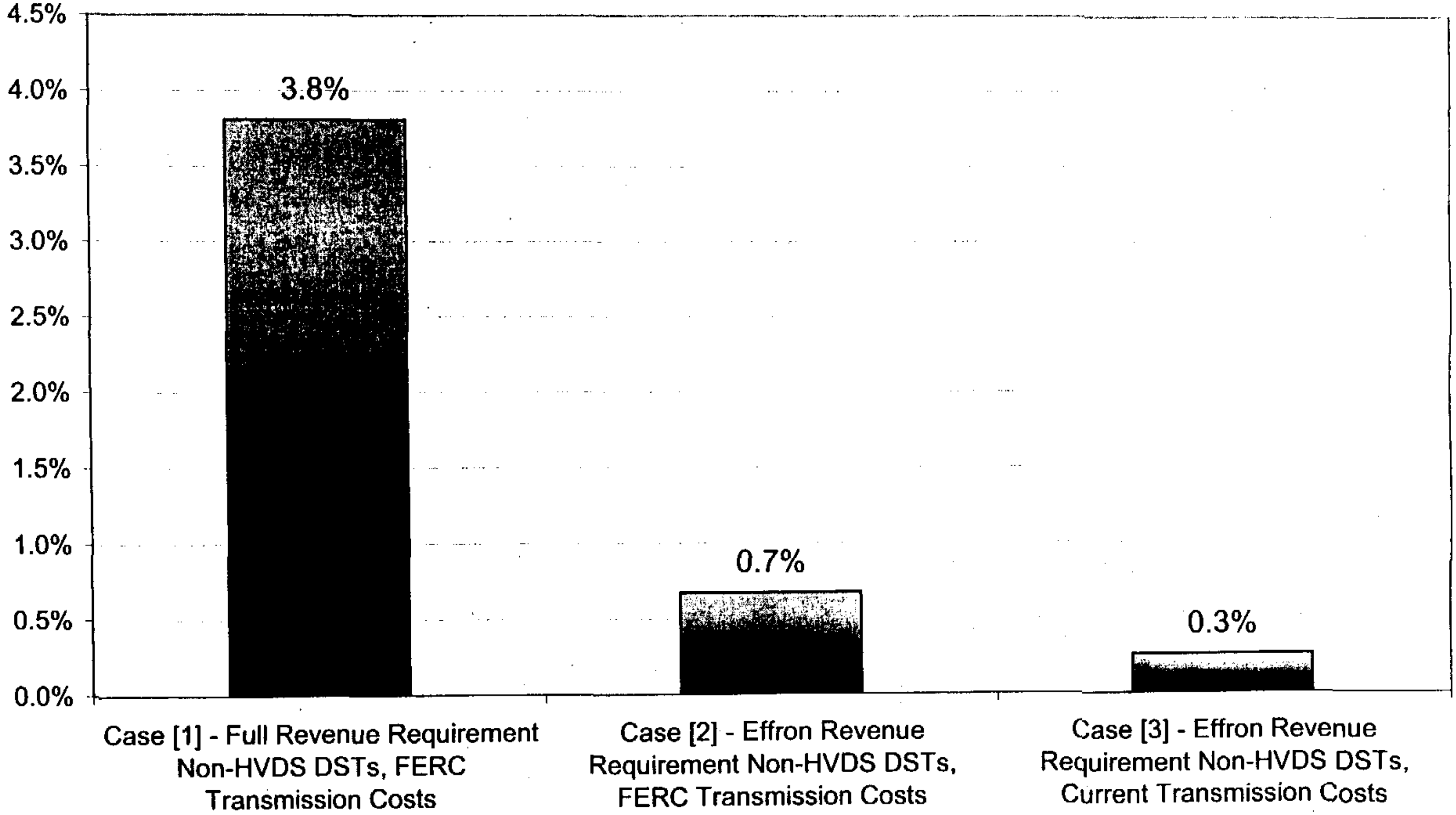
Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$19	$20	($38)	($8)	($7)	No	No
3A	$116	$57	($88)	($33)	$51	Yes	No
3B	$45	$65	($101)	($38)	($28)	No	No
3C	$104	$157	($244)	($91)	($74)	No	No
3D-IRMA	$121	$226	$0	($131)	$215	Yes	No
3E-IRMA	$42	$179	$0	($102)	$119	Yes	No
3F	$101	$311	($483)	($180)	($251)	No	No
4A	$91	$127	($188)	($24)	$7	Yes	No
4B	$273	$321	($474)	($60)	$60	Yes	No
4C	$734	$1,119	($1,652)	($208)	($8)	No	No
4D	$216	$535	($791)	($99)	($138)	No	No
4E	$360	$1,029	($1,520)	($194)	($324)	No	No
5B	$883	$1,082	($1,272)	($338)	$355	Yes	No
5C	$998	$1,875	($2,204)	($554)	$114	Yes	No
5D	$1,478	$4,086	($4,804)	($1,162)	($403)	No	No
5E	$1,272	$4,117	($4,841)	($1,096)	($549)	No	No
5F	$1,471	$4,923	($5,789)	($1,331)	($725)	No	No
6B	$1,325	$2,359	($2,891)	($297)	$496	Yes	No
6C	$1,530	$3,787	($4,642)	($567)	$107	Yes	No
6D	$1,755	$4,284	($5,252)	($595)	$193	Yes	No
6E	$1,918	$6,907	($8,466)	($945)	($586)	No	No
7B	$2,905	$3,668	($3,815)	($640)	$2,118	Yes	No
7C	$3,673	$9,347	($9,723)	($1,726)	$1,571	Yes	No
7D	$3,693	$12,684	($13,194)	($2,105)	$1,078	Yes	No
7E	$6,481	$22,900	($23,821)	($3,751)	$1,809	Yes	No
7F	$2,544	$10,032	($10,436)	($1,485)	$655	Yes	No
8C	$7,725	$20,278	$0	($2,342)	$25,661	Yes	No
8D	$10,581	$33,817	$0	($3,780)	$40,619	Yes	No
8E	$11,761	$45,960	$0	($5,057)	$52,664	Yes	No
8F	$10,202	$43,962	$0	($4,787)	$49,377	Yes	No
9C	$13,975	$43,816	$0	($4,742)	$53,049	Yes	No
9D	$12,096	$42,433	($30,943)	($4,842)	$18,743	Yes	No
9E	$17,921	$66,657	($58,865)	($7,284)	$18,429	Yes	No
10B	$12,241	$97,107	($1,873)	($8,765)	$98,710	Yes	No
10D	$11,999	$112,677	$0	($9,556)	$115,121	Yes	No
10E	$9,220	$123,409	($17,001)	($10,095)	$105,533	Yes	No
SH-B	$59	$70	$0	($41)	$89	Yes	No
SH-C	$341	$472	$0	($89)	$725	Yes	No
SH-D	$748	$1,564	$0	($291)	$2,021	Yes	Yes
HV-E	$37,392	$189,893	$0	($15,664)	$211,621	Yes	No
HV-F	$24,287	$77,177	$0	($7,490)	$93,974	Yes	No

Case 3: Comparison of Current PPO Components to Proposed PPO Components for Selected Customer Accounts (DSTs based on Current Rate Design & Effron Revenue Requirement. Transmission Costs are as Currently in Effect)

Customer Name	Change in Annual DST Costs	Change in Annual Transmission Costs	Change in Annual CTC Costs	Change in Annual PPO Energy Costs	Change in Annual Total PPO Costs	PPO Savings Diminish?	Bundled Rate Becomes More Economic?
2B	$19	$0	($18)	($8)	($7)	No	No
3A	$116	$0	($32)	($33)	$51	Yes	No
3B	$45	$0	($36)	($38)	($28)	No	No
3C	$104	$0	($87)	($91)	($74)	No	No
3D-IRMA	$121	$0	$0	($131)	($11)	No	No
3E-IRMA	$42	$0	$0	($102)	($60)	No	No
3F	$101	$0	($173)	($180)	($251)	No	No
4A	$91	$0	($61)	($24)	$7	Yes	No
4B	$273	$0	($153)	($60)	$60	Yes	No
4C	$734	$0	($534)	($208)	($8)	No	No
4D	$216	$0	($255)	($99)	($138)	No	No
4E	$360	$0	($491)	($194)	($324)	No	No
5B	$883	$0	($190)	($338)	$355	Yes	No
5C	$998	$0	($330)	($554)	$114	Yes	No
5D	$1,478	$0	($719)	($1,162)	($403)	No	No
5E	$1,272	$0	($724)	($1,096)	($549)	No	No
5F	$1,471	$0	($866)	($1,331)	($725)	No	No
6B	$1,325	$0	($615)	($297)	$413	Yes	No
6C	$1,530	$0	($988)	($567)	($26)	No	No
6D	$1,755	$0	($1,118)	($595)	$42	Yes	No
6E	$1,918	$0	($1,802)	($945)	($829)	No	No
7B	$2,905	$0	($643)	($640)	$1,622	Yes	No
7C	$3,673	$0	($1,638)	($1,726)	$309	Yes	No
7D	$3,693	$0	($2,222)	($2,105)	($634)	No	No
7E	$6,481	$0	($4,013)	($3,751)	($1,283)	No	No
7F	$2,544	$0	($1,758)	($1,485)	($699)	No	No
8C	$7,725	$0	$0	($2,342)	$5,383	Yes	No
8D	$10,581	$0	$0	($3,780)	$6,801	Yes	No
8E	$11,761	$0	$0	($5,057)	$6,704	Yes	No
8F	$10,202	$0	$0	($4,787)	$5,415	Yes	No
9C	$13,975	$0	$0	($4,742)	$9,233	Yes	No
9D	$12,096	$0	($9,084)	($4,842)	($1,831)	No	No
9E	$17,921	$0	($12,932)	($7,284)	($2,295)	No	No
10B	$12,241	$0	($268)	($8,765)	$3,208	Yes	No
10D	$11,999	$0	$0	($9,556)	$2,443	Yes	No
10E	$9,220	$0	($2,720)	($10,095)	($3,595)	No	No
SH-B	$59	$0	$0	($41)	$18	Yes	No
SH-C	$341	$0	$0	($89)	$253	Yes	No
SH-D	$748	$0	$0	($291)	$457	Yes	No
HV-E	$37,392	$0	$0	($15,664)	$21,728	Yes	No
HV-F	$24,287	$0	$0	($7,490)	$16,796	Yes	No

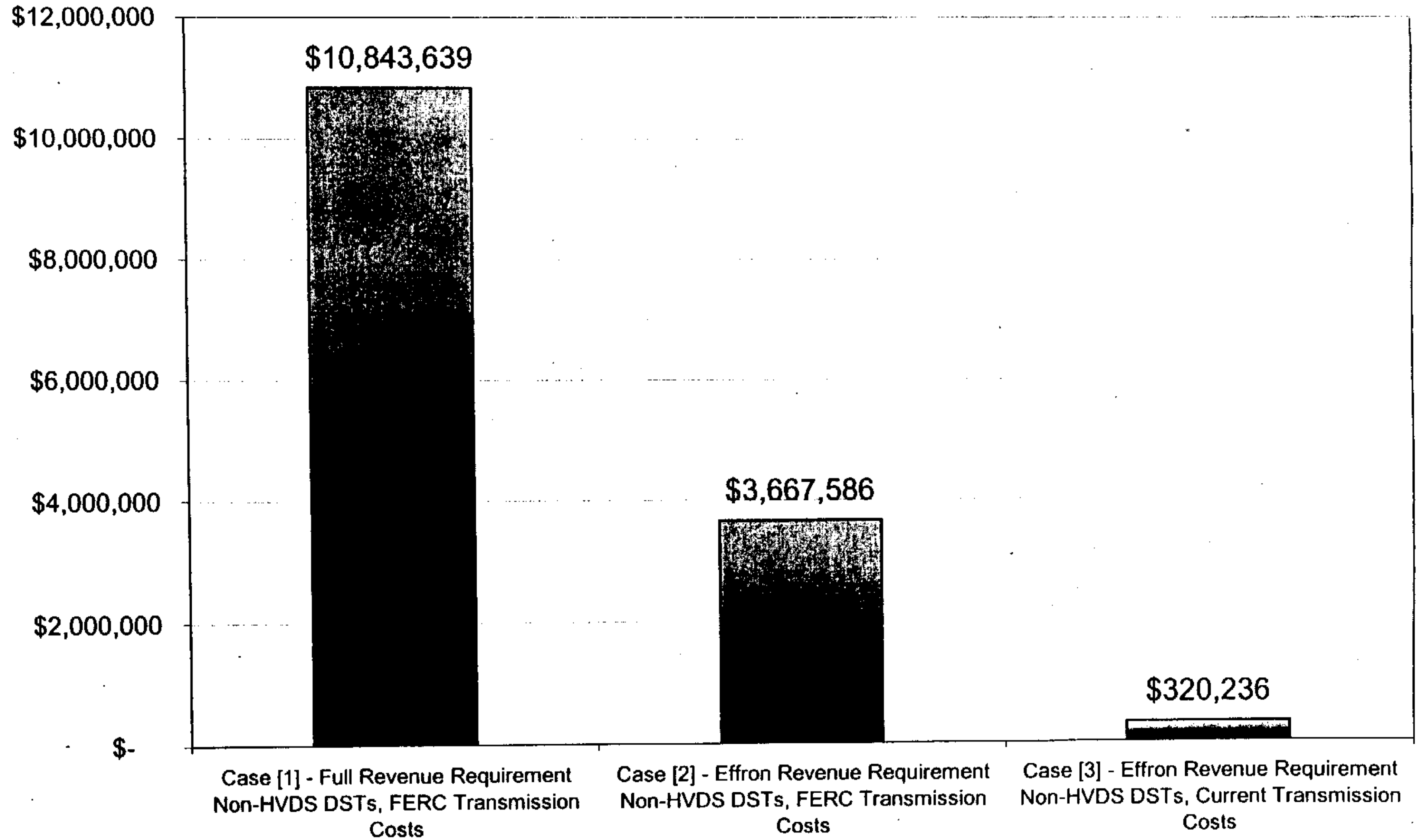
CHART A CONTAINS CONFIDENTIAL INFORMATION

Chart B - Average % Increase in Annual PPO Cost



tables and charts for spilky-oconnor rebuttal testimony-public.xls, Chart B

Chart C - Estimated Total Annual $ Increase for NE Served Accounts



tables and charts for spilky-oconnor rebuttal testimony-public.xls, Chart C

CHART D CONTAINS CONFIDENTIAL INFORMATION

CHART E CONTAINS CONFIDENTIAL INFORMATION

D

<u>ICC Docket No. 01-0423</u>
Response of Commonwealth Edison Company
To ARES Coalition's Sixth Set of Data Requests
ARES 6.01 through ARES 6.02
To Commonwealth Edison Company
Dated August 3, 2001

ARES 6.01 Attached please find a copy of the text of an article written by Carl Segneri, Vice President of Substations and Transmission for ComEd Energy Delivery, that appeared in the May 2001 issue of Transmission & Distribution World. With respect to the article, please answer the following:

a. Please provide a copy of the May 2001 issue of Transmission & Distribution World magazine that contains the article.
b. Does the Company agree with the contents of the article? If not, please identify each sentence the Company does not agree with and provide a detailed explanation of why the Company does not agree.
c. Please provide all notes prepared by Mr. Segneri in writing this article and all other documents reviewed or relied upon by Mr. Segneri. Please identify each person with whom Mr. Segneri consulted in preparing this article.
d. Please provide all drafts of this article.
e. Please provide all comments or mark-ups or similar documents that Mr. Segneri received in preparing to write this article. Please identify the source of each such document.
f. Please provide all comments, critiques, reviews or similar documents that Mr. Segneri received from Company personnel regarding this article after it was published. Please identify the source of each such document.
g. Referring to the $1.5 billion reliability improvement plan referenced in the second paragraph of the article:

    1. Please indicate what portion (both percentage and dollar amount) of the $1.5 billion reliability improvement plan Edison is seeking to recover in the instant proceeding. Please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
    2. Please indicate the portion of the $1.5 billion the Company actually spent in 2000. Please indicate the FERC Account in which those costs were recorded.
    3. Please indicate the amount of the costs associated with the $1.5 billion reliability plan that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
    4. Please explain in detail why such costs were excluded from the Company's test year.

h. Regarding the task force and Edison's investigation of the 1999 outages referenced in the article:
   1. Please indicate whether Edison seeks recovery in the instant proceeding of any costs associated with the task force and Edison's investigation of the 1999 outages.
   2. If Edison is seeking to recover such costs, please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
   3. Please indicate the amount that the Company actually spent in 2000 on the task force and its investigation of the 1999 outages. Please identify the FERC Account in which these expenses were recorded.
   4. Please indicate the amount of the costs associated with the task force and its investigation of the 1999 outages that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
   5. Please explain in detail why such costs were excluded from the Company's test year.

i. Please provide a copy of the 450-page recovery plan, the September 1999 Investigation Report referenced in the article.

j. Regarding the aerial inspection of the overhead transmission system referenced in the article:
   1. Please indicate whether the costs associated with the aerial inspection of the overhead transmission system are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding.
   2. If so, please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
   3. Please indicate the actual amount the Company spent during 2000 for aerial inspections of its transmission system. Please identify the FERC Account in which these costs were recorded.
   4. Please identify the last time prior to 2000 that the Company performed an aerial inspection of the overhead transmission system.
   5. Why did the Company wait until 2000 to perform an aerial inspection of the overhead transmission system?

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To Commonwealth Edison Company
Dated August 3, 2001

6. Please indicate the amount of the costs associated with the aerial inspection of the overhead transmission system that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
7. Please explain in detail why such costs were excluded from the Company's test year.

k. Regarding tree trimming expenses referenced in the article:
   1. Please indicate the specific amount of tree trimming expenses that are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding.
   2. Please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
   3. Please indicate the actual amount the Company spent during 2000 on tree trimming. Please identify the FERC Account in which these costs were recorded.
   4. Please indicate the tree trimming cycle that was assumed in the Company's proposed revenue requirements. Please fully explain the basis for this assumption. What assumption was used in Edison's first delivery services rate proceeding?
   5. Please provide a copy of the contract with Asplundh Tree Experts ("ATE"). Please explain the basis upon which ATE is compensated (flat fee per year, multi-year with escalating fee, per hour, etc.)
   6. Please indicate the amount of the costs associated with tree trimming the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
   7. Please explain in detail why such costs were excluded from the Company's test year.

l. Regarding the additional monitoring that was installed to identify potential degradation of the transformers referenced in the article:
   1. Please indicate the specific amount of costs associated with such additional monitoring that is included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding.

2. Please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
3. Please indicate the actual amount the Company spent during 2000 on such additional monitoring. Please identify the FERC Account in which these costs were recorded
4. Please indicate the specific amount of costs associated with such additional monitoring that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
5. Please explain in detail why such costs were excluded from the Company's test year.

m. Please indicate the specific costs associated with the more than 2100 contractors that assisted Edison in the distribution system and substation maintenance projects, as well as smaller projects that are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding. Alternatively, please explain in detail why such costs were excluded from the Company's test year.

n. Regarding the Company's contracts with Kenny Construction, Asea Brown Boveri ("ABB"), General Electric, and EPRI that are referenced in the article.
1. For each contractor, please indicate the amount that was paid to the contractor that is included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding. Please provide a specific reference to a page or line number in a pre-filed exhibit referencing these costs.
2. For each contractor, please indicate the actual amount the Company spent during 2000 on such contracts. Please identify the FERC Account in which these costs were recorded.
3. For each contractor, please indicate the specific amount of costs associated with the contract that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
4. Please explain in detail why such costs were excluded from the Company's test year.

o. Regarding the six Chicago substations known as the "six-pack" referenced in the article:
1. Please indicate the specific expenditures for the "six-pack" that are included in the Company's proposed 2000 test year

or for which a pro forma adjustment to the test year is sought in the instant proceeding.

2. Please indicate the actual amount the Company spent during 2000 on the "six pack." Please identify the FERC Account in which these costs were recorded.
3. Please indicate the specific amount of cost associated with the "six-pack" that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
4. Please explain in detail why such costs were excluded from the Company's test year.

p. Regarding the Company securing of temporary and portable generators during the year 2000, as discussed in the article:
   1. Please indicate the specific expenditures related to temporary and portable generators that are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding.
   2. Please indicate the actual amount the Company spent during 2000 on the temporary and portable generators. Please identify the FERC Account in which these costs were recorded.
   3. Please indicate the specific amount of costs associated with the temporary and portable generators that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
   4. Please explain in detail why such costs were excluded from the Company's test year.

q. Does the Company agree that " In truth, the reliability hole that ComEd found itself in at the end of summer of 1999 was dug over a long period of time." If not, please explain in detail why not. If so, please explain in detail how this was taken into account in setting the Company's revenue requirements.

r. Does the Company agree that "To make a bad situation worse, through the years the Company had neglected routine maintenance in favor of other projects." If not, please explain in detail why not. If so, please explain in detail how this was taken into account in setting the Company's revenue requirements.

s. Please outline the specific tasks, projects, and process improvements that are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding, including but not limited to the more than 330 distribution feeder installations and upgrades, 27 large substation transformer upgrades or expansion projects, and transmission line inspections and repairs that are referenced in the article.

t. Does the Company agree that during 2000, "ComEd employees worked an average of more than 60 hr a week . . ."? If not, please explain in detail why not.
   1. Please indicate the specific expenditures related to employee overtime that are included in the Company's proposed 2000 test year or for which a pro forma adjustment to the test year is sought in the instant proceeding.
   2. Please indicate the actual amount the Company spent during 2000 on employee overtime. Please identify the FERC Account in which these costs were recorded.
   3. Please indicate the specific amount of costs associated with employee overtime that the Company incurred in 2000, but that is not included in the Company's proposed test year in the instant proceeding.
   4. Please explain in detail why such costs were excluded from the Company's test year.

SUPPLEMENTAL RESPONSE:

ComEd objects to various portions of this data request. The request, which, at six pages, is almost as long as the article to which it refers, seeks production on a blanket basis of a variety of material that is neither relevant nor material within the meaning of 83 Illinois Administrative Code Section 200.340 and is not reasonably calculated to lead to the discovery of admissible evidence. The request for such information also imposes unreasonable burdens and expense. Without waiving its objections, substantive answers to the request are provided below.

ComEd notes that the referenced article was written for publication in a trade journal as a short summary of a complex work in progress. As a result, implicit assumptions in the data request that specific statements in the article relate to quantitative studies, analyses, or bodies of data are frequently incorrect. Moreover, it is not reasonable to expect ComEd to analyze this article and provide a detailed discussion of each instance where Mr. Segneri did not include a detail, a qualification, or an explanation in the interest of authoring a readable article suitable for timely publication.

a. A copy of the article is attached hereto.

b. ComEd agrees with the basic conclusions stated in the article. As to each individual sentence, Mr. Segneri's article was intended for publication in, and was published in, a trade journal as a short summary of a complex work in progress. The article's length and style were governed by restrictions that imposed significant limitations on the detail with which he could discuss those conclusions. It is not reasonable to expect ComEd to analyze this article and provide a detailed discussion of each instance where Mr. Segneri did not include a detail, a qualification, or an explanation in the interest of authoring a readable article suitable for timely publication. For example, there are numerous references to the types and amount of work that were performed, broad estimations of costs, descriptions of work and other such matters. These comments were not made at a level of detail appropriate for testimony or documentary evidence.

The article also states matters of opinion by Mr. Segneri, which opinions were not expressed utilizing the legal standards applicable to litigation or a legal proceeding. Rather, Mr. Segneri's opinions stated in the article reflect his own views using the technique of self-critical analysis common in utility engineering practices. Such techniques and analyses are directed towards finding areas for improvement, and are not prepared using the legal standards of reasonableness and prudence utilized in legal proceedings. The statements of opinion, while representing Mr. Segneri's views utilizing the self-critical hindsight methodology employed by Mr. Segneri for the article, therefore do not constitute admissions with respect to legal conclusions by ComEd.

In particular, it is ComEd's view that the actions reflected in the article and that are now the subject of this rate case were prudent and reasonable based upon the information reasonably known and alternative courses of action available to ComEd at the time decisions were made.

c. Mr. Segneri did not retain the notes which he used in preparing and writing this article. Mr. Segneri spoke with numerous ComEd personnel about subjects addressed in the article in the course of performing his job responsibilities, but Mr. Segneri did not discuss these substantive subjects in the context of preparing the article, except that he did have conversations with and receive comments from Mr. David Helwig and Mr. Jim Williams about the article. Mr. Segneri also spoke with ComEd media relations personnel about non-substantive aspects of the article.

d. No drafts of the article exist.

e. Mr. Segneri did not receive any "comments or mark-ups or similar documents" from any third person in preparing the article. As discussed in response to ARES data request 6.1(c), Mr. Segneri did not retain his own notes or any documents given to him by Messrs. Helwig or Williams.

f. No such documents exist.

g. (1) The "blueprint for change" involves a vast array of tasks, projects, and process improvements, the costs of which include both distribution investments and expenses, many of which were begun or completed in late 1999 or 2000 and others of which have been completed in 2001 or are still ongoing. ComEd tracks its distribution investments and expenses in its information systems and books in accordance with its business processes and reporting obligations. ComEd does not track distribution expenses and investments along the lines of the "blueprint for change." To identify the portions of ComEd's adjusted test year distribution investments and expenses which were included in the "blueprint for change" calculations would require analyzing hundreds if not thousands of projects and activities and to some extent performing a functionalization process to confirm the direct assignment or allocation of the associated costs, and any such analysis is complicated by the fact that investments and expenses have multiple drivers, e.g., dealing with load growth and maintaining or improving reliability. Some of the major items included in the "blueprint for change", e.g., some of the costs associated with certain Chicago substation work, are discussed or identified, including in terms of costs included in the proposed revenue requirement, in ComEd pre-filed Exhibits 4.0, 5.0, and 6.0 and the relevant attachments thereto.

(2) Please see ComEd's response to subpart (g)(1). ComEd's relevant distribution investments and expenses are reflected appropriately in numerous FERC Accounts. See, e.g., ComEd Exhibits 4.0 and

5.0 and the relevant attachments thereto. The costs associated with the "blueprint for change" as such appropriately are not recorded in any FERC Accounts in any manner tied to that report.

(3) Please see ComEd's response to subpart (g)(1). ComEd has included appropriate distribution expenses in its adjusted test year. ComEd has included appropriate distribution investments, including a fraction of its distribution investments placed in service in the first or second quarter of 2001, in its adjusted test year. ComEd did not include 100% of the costs incurred in 2000 and associated with the "blueprint for change" in its adjusted test year, e.g., ComEd made a downward adjustment for tree management expenses and investments made in 2000 may not have been recorded until 2001 (or may not yet be recorded) and may or may not be included in ComEd's proposed rate base. However, it is not practical to examine hundreds if not thousands of items to quantify the aggregate amount not included.

(4) Please see response to sub-subpart (g)(3).

(h) (1) The referenced task force existed during 1999 and its costs were expensed in that year. ComEd is not seeking recovery of 1999 O&M costs in this proceeding.

(2) Not applicable. See response to sub-subpart (h)(1).

(3) Not applicable. See response to sub-subpart (h)(1).

(4) Not applicable. See response to sub-subpart (h)(1).

(5) Not applicable. See response to sub-subpart (h)(1).

(i) This voluminous document has already been made available for inspection at ComEd's Lincoln Centre offices in response to prior data requests and remains available for inspection.

(j) This subpart refers to an inspection of the transmission system, which by its terms is not jurisdictional and would not be relevant. However, ComEd's investigation of its aerial inspection activities has shown that Mr. Segneri's reference was to a common use of the term "transmission" and not precise. As noted in response to subpart (a) above, Mr. Segneri's article was intended for publication in and was published in a trade journal as a short summary of a complex work in progress. The article's length and style were governed by restrictions that imposed significant limitations on the detail with which he could discuss those conclusions. As to the individual sentence referenced, the aerial inspection was of the high-voltage system, which includes both transmission and high-voltage distribution elements. Expenses relating to the transmission system are not relevant. Expense data is not separately retained or calculated for the aerial inspection of just the distribution facilities.

(1) See response to subpart (j), above.

(2) Not applicable. These costs are not separately identified in the filing.

(3) Expenses related to the transmission system are not included in the revenue requirement and are not relevant.

(4) Expenses related to the transmission system are not included in the revenue requirement and are not relevant. In the past, ComEd has conducted inspections of particular high-voltage distribution facilities periodically, as required. For example, in 1996 several line surrounding BP Amoco, Mobil Oil and Caterpillar facilities were inspected.

(5) The data request makes an incorrect assumption. The article does not state or imply that ComEd delayed, imprudently or otherwise, an aerial inspection that it had determined was required.

(6) As noted above, the majority of the cost of the inspection was allocated to transmission and, thus, not included in the state-jurisdictional distribution revenue requirement.

(7) These transmission costs are not costs of providing distribution service.

(k) ComEd understands this data request to refer to what has been called "tree management" in this proceeding. Given this, ComEd answers as follows:

(1) $46,357,910.

(2) See Schedule C-2.11 and Workpaper C-2.11(a), contained in Appendices C and D to ComEd Ex. 4.0, the direct testimony of Mr. Hill. See also Direct Testimony of Mr. Voltz, ComEd Ex. 5.0, pp. 18 and 21.

(3) $46,870,844, recorded in FERC Account 593

(4) A 4-year cycle was used to develop the revenue requirement. ComEd used a 4-year cycle because that is the actual cycle on which ComEd currently trims trees. The 1997 delivery services rate case proposed implementing a 4-year cycle, but the Commission did not approve ComEd's expenses of implementing that cycle.

(5) This contract is Confidential. A copy of the contract will be produced subject to the Protective Order.

(6) ($512,934)

(7) See the direct testimony of Mr. Voltz, ComEd Exhibit 5.0, pp. 17, 18, 21-22.

(l) (1) ComEd does not have available data that would permit with reasonable effort disaggregating all of the costs included in the adjusted test year of or "associated with" distribution monitoring equipment in relation to monitoring of transformers as opposed to other monitoring. ComEd Exhibit 5.2 does include as a separate line item costs of certain distribution monitoring equipment that monitors transformers and that was declared in service in January and February 2001 and included in the adjusted test year. See also ComEd Exhibit 4.0, Schedule C, Schedule B-2.2, and Schedule D, workpaper WPB-2.2(a). ComEd also incurred costs for distribution monitoring equipment in 2000 that are included in the adjusted test year.

(2) See ComEd's response to subpart (l)(1).

(3) See ComEd's response to subpart (l)(1). At the time that ComEd prepared its schedules to ComEd Exhibit 4.0, these costs were recorded in FERC Accounts 101 or 106.

(4) ComEd does not have available data that would permit with reasonable effort identifying such costs.

(5) See ComEd's response to subpart(l)(4).

(m) The "over 2100 contractors" referred to in the article is an estimate of the number of contractor personnel -- not contracting entities -- assisting with various distribution system and substation maintenance projects over a period that is not co-extensive with the 2000 test year. These projects included new projects, existing projects, small and large projects. Approximately 1200 of the contractor personnel assisted with tree-trimming projects. Some of the associated costs are capital costs, other costs were expensed. ComEd does not have data from which the requested information can be calculated with reasonable effort because the underlying information appropriately is not tracked in this manner. It is clear that not all of these costs are included in the adjusted test year. The relevant costs expensed outside the test year are not included in the test year. Also, some of the costs expensed in the test year are not included in the adjusted test year, e.g., ComEd made a downward adjustment to its tree management expenses. Some the capital costs also are not included in the test year, e.g. costs spent on the Lakeview project because that project was not placed in service. ComEd does not track information so as to be able to provide the "specific costs associated with the more than 2,100 contractors." Further, to compile such information would not be reasonably practical.

(n) ComEd understands subpart (n) to be addressed to (1) the referenced consulting by EPRI, GE, Kenny, and ABB with Mr. Helwig and his team in 1999; and (2) work by GE, Kenny, and ABB on the "Chicago six-pack" in late 1999 - early 2001. (Assuming that subpart (n) as to GE instead was intended to be addressed to work other than work on the six-pack, then the responsive data is not tracked as such and thus is not available.) Please note, the Lakeview project component of the six-pack was not declared in service and its costs are not in the adjusted test year, and the Jefferson project component later was removed from the six-pack.

(1) As to the referenced consulting work, no expenses were included in the test year. As to the work by GE, Kenny, and ABB on the six-pack, please see ComEd's response to Staff data request BAL-2.01. Please note that ComEd's response to Staff data request BAL-2.01 includes work on the six-pack as well as certain

other identified work. Please also note that ComEd's response to Staff data request BAL-2.01 as to the six-pack includes data from late 1999 to early 2001. Capital costs are not recorded in FERC Accounts on an as-incurred calendar basis, and disaggregating the 2000 six-pack costs from the late 1999 and the early 2001 costs would require examining a voluminous number of documents. There is not an individual reference in ComEd's June 1, 2001, filing, that compiles and disaggregates from all other costs the entirety of the six-pack costs. However, ComEd Exhibits 4.0, 5.0, and 6.0, and their relevant attachments identify various components of the six-pack work and their costs.

(2) As to the referenced consulting, no expenses were included in the test year. As to the work by GE, Kenny, and ABB on the six-pack, please see ComEd's response to sub-subpart (n)(1). The costs of the six-pack work were recorded in FERC Account 362, except that costs of the Diversey TSS new feeder installation referenced in ComEd Exhibit 5.1 were included in FERC Accounts 366 and 367.

(3) As to the referenced consulting, none. As to the six-pack, the Lakeview costs are not included in the adjusted test year. The contract price for Lakeview was $6,842,586.

(4) As to the referenced consulting, the costs were incurred prior to the test year. As to the six-pack, as noted above, the Lakeview project component of the six-pack was not declared in service during the test year.

(o) (1) See ComEd's response to subpart (n). The aggregate costs included in the adjusted test year for the six-pack are $126,930,867. This figure is based on the relevant methodologies and data stated in ComEd's direct testimony and attachments thereto (*e.g.*, ComEd Exs. 5.1, 5.3, and 6.1).

(2) See ComEd's response to subpart (n).

(3) See ComEd's response to subpart (n).

(4) See ComEd's response to subpart (n).

(p) ComEd understands that, per the referenced article, this subpart to refer to temporary and portable generation that was used to reinforce distribution system elements, and not to generation procured for supply reasons.

(1) $1,380,797. Associated expenses were recorded in FERC Accounts 580, 581, 592, 595.

(2) See sub-subpart (p)(1). No *pro forma* adjustment related to generators.

(3) None.

(4) Not applicable.

(q) See response to subpart (a). Mr. Segneri's article was intended for publication in and was published in a trade journal as a short summary of a complex work in progress. The article's length and style were governed by restrictions that imposed significant limitations on the detail with which he could discuss those conclusions. As to the individual sentence quoted above, events that occurred prior to 1999 did contribute to the reliability "hole" of 1999. For a discussion of how ComEd addressed this fact in determining its revenue requirement, please see the direct testimony of Ms. Arlene Juracek, ComEd Ex. 1.0, and ComEd's response to AG data request 1.01 expanding on that testimony.

(r) See response to subpart (a). Mr. Segneri's article was intended for publication in and was published in a trade journal as a short summary of a complex work in progress. The article's length and style were governed by restrictions that imposed significant limitations on the detail with which he could discuss those conclusions. As to the individual sentence quoted above, ComEd does not understand the individual sentence quoted above in context to be intended to characterize all or most maintenance practices. If it were to be so read, ComEd would not agree with it. ComEd otherwise incorporates its response to subpart (q).

(s) The request made in this subpart has nothing to do with Mr. Segneri's article and transparently is unreasonable. Specific tasks, projects, and process improvements included in ComEd's proposed 2000 adjusted test year are available in sources including ComEd's June 1, 2001 filing, ComEd's FERC Form 1, and ComEd's responses to numerous data requests. An exhaustive list of every single task, project, and process improvement that is included in the adjusted test year probably would include on the order of hundreds of thousands of items. Such a blanket request is also not reasonably calculated to lead to the discovery of admissible evidence.

(t) ComEd disagrees. The reference in the article was to a limited group of personnel working on certain recovery plan efforts, principally in 1999. With respect to that group, the statement was an estimate. Details regarding overtime during the test year have been provided in response to other data requests.

(1) See ComEd's Corrected Response to Staff data request GEG-2.02 regarding capitalized overtime. With respect to overtime included in distribution expense accounts, ComEd has available the data on salaried and hourly overtime contained on the following table:

580000	1,367,689.24
580006	221,322.06
581000	655,834.12
582000	2,272,958.54
583000	1,401,707.72
584000	466,935.73
585000	29,634.45
586000	129,118.43
586006	2,482.57
587021	11,493.39
587023	1,629,729.61
588000	42,009.88
590000	139,242.10
592000	6,431,833.11
593000	19,331,080.77
594000	7,419,940.82
594006	44,408.84
595000	774,396.76
596000	383,549.48
597000	16,255.67
598000	13,141.51

Total 42,784,764.80

Please note that this data does not reflect the refunctionalization of expenses included in the test year. Please also note that this data does not reflect the reduction in overtime included in the revenue requirement due to the storm expense adjustment.

(2) This sub-subpart seeks data concerning company-wide labor expenses, many of which are neither jurisdictional nor included in the proposed revenue requirement, and are thus irrelevant. For jurisdictional expenses, please see sub-subpart (t)(1).

(3) This sub-subpart is explicitly addressed to non-jurisdictional expenses that are outside of the revenue requirement, and thus is irrelevant.

(4) This sub-subpart is not addressed to company-wide labor expenses, many of which are neither jurisdictional nor included in the proposed revenue requirement. Further answering, ComEd states that excluded expenses were removed for that reason, i.e., they were not regarded as costs of providing state-jurisdictional delivery services.

Feature

Reversal of Fortunes

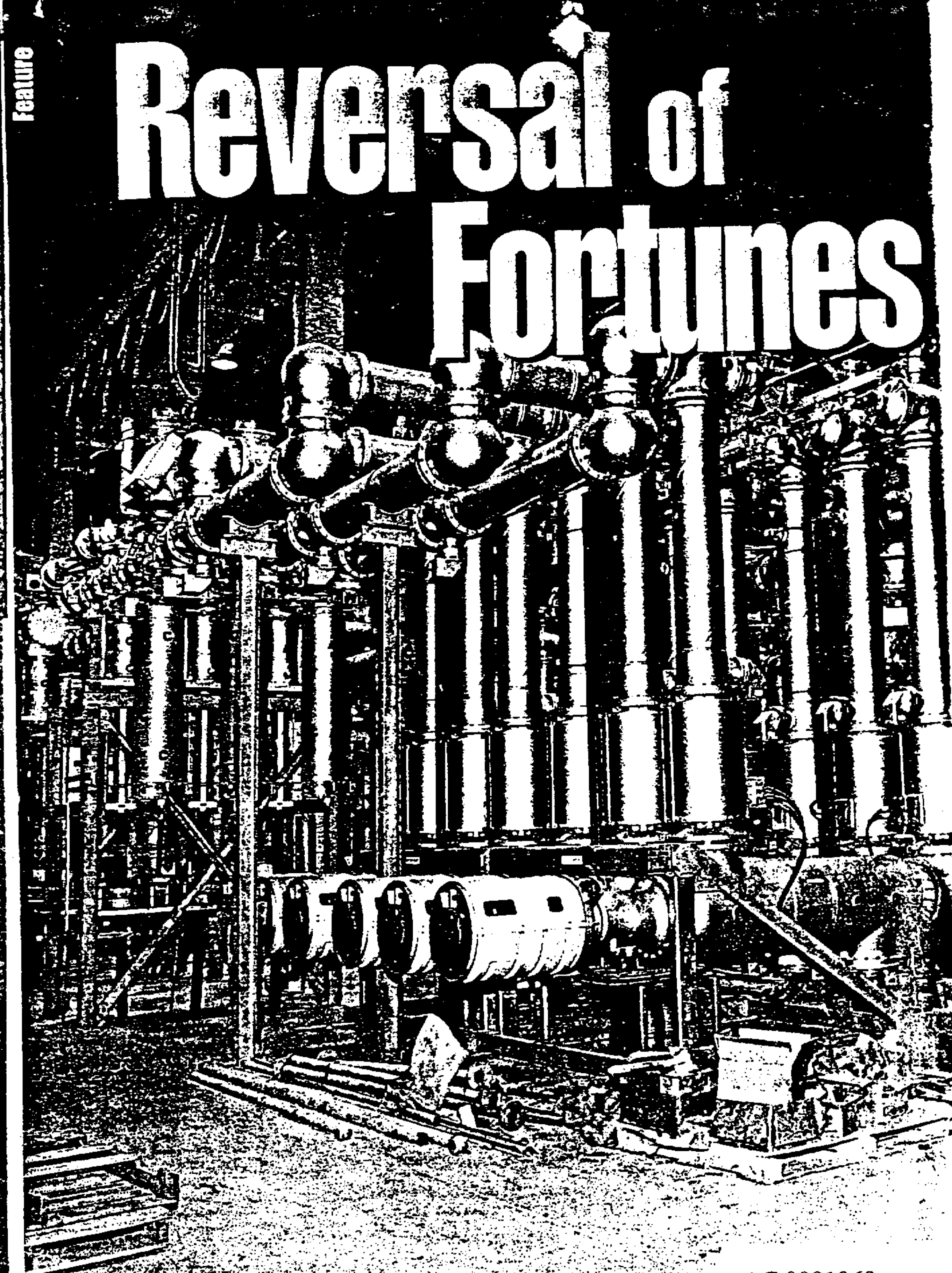

Fig. 1. Inside view of enclosed SF_6 Kingsbury 138-kV substation.

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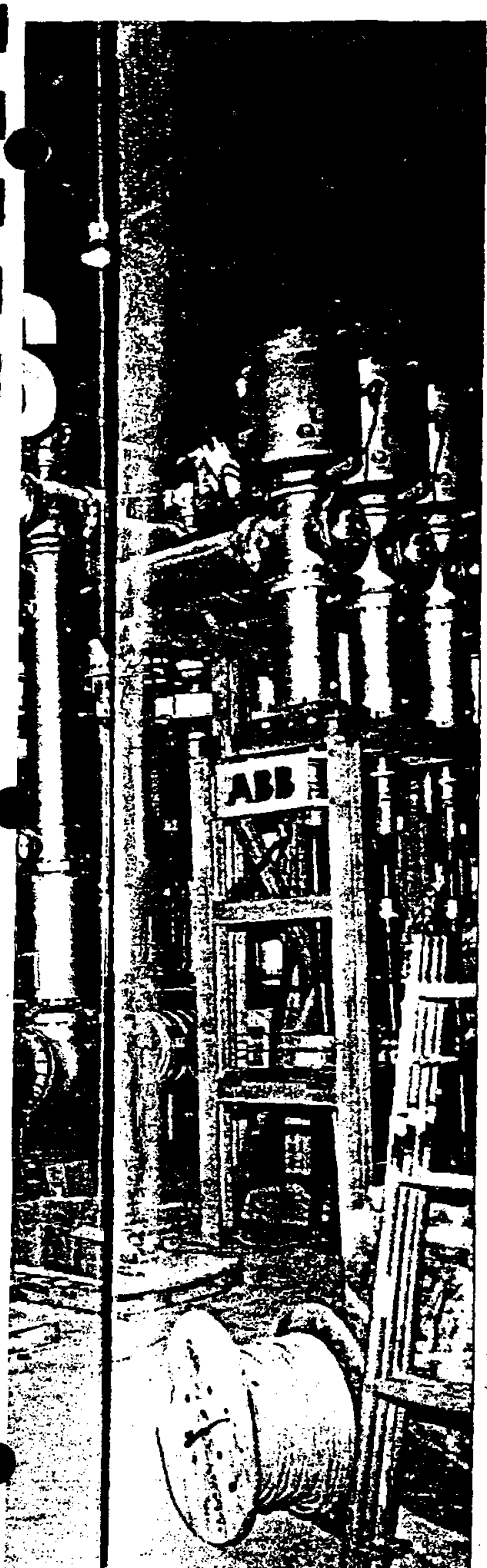
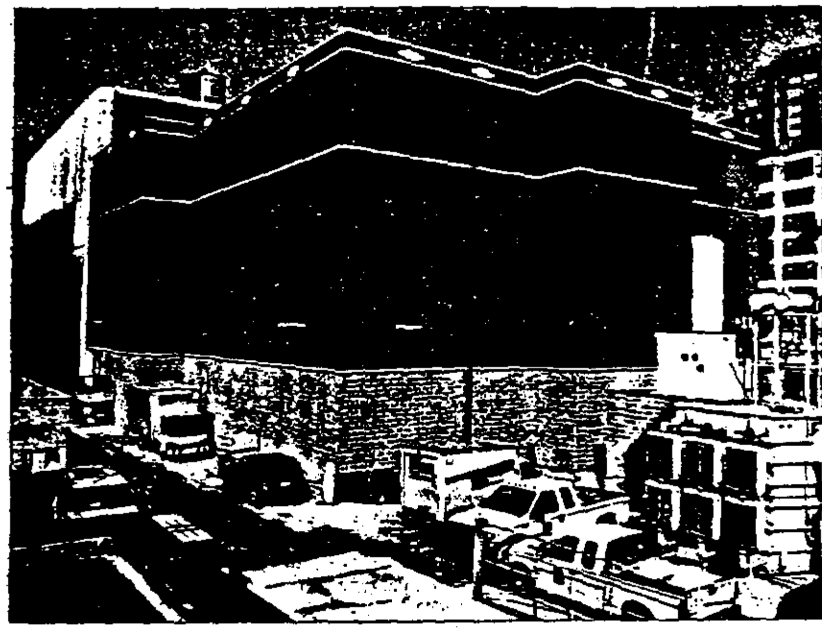


ComEd rebuilds its system and its reputation.



Photography by David Boenzi

Fig. 2. The exterior of the Kingsbury Substation.

By Carl Segneri, ComEd

In the summer of 1999, the United States was struck by a series of major utility outages as aging T&D systems proved vulnerable to the twin challenges of extreme heat and extreme demand. New York City, New York, was hit by its worst blackout in more than 20 years. Half a million customers lost power in New Orleans, Louisiana. And in Chicago, Illinois, as a month of recurring outages crippled vital parts of a sweltering city, an angry Mayor Richard M. Daley expressed the voice of many when he demanded immediate action. ComEd, he declared, needed to rebuild its system and do it now, starting at "ground zero."

In response, ComEd's new chairman, John Rowe, launched a comprehensive overhaul of its T&D system, a US$1.5 billion reliability improvement plan that industry experts called "unprecedented." Rowe demanded a fundamental *core* change aimed at producing a T&D system that met or exceeded industry standards. His message was simple: "Nothing matters if we don't keep the lights on."

The Long Hot Summer of 1999

In 1999, the first major blackout of Chicago's late summer heat wave began beneath the manholes located along California Ave. In the early morning hours of Friday, July 30, the 12-kV line feeding Cortland Substation short circuited. Within hours, a series of falling T&D dominos had two major substations down, with the power gone and the air conditioning out in nearly 100,000 homes. It was the hottest day of the summer, in what the *Chicago Tribune* later calculated was the fourth hottest week of the century.

Public anger rose along with the temperature as other T&D components failed over the next five weeks. Manhole fires occurred on August 9 and 10. Chicago's central business district, the Loop, went dark on August 12. Later, power failed at four Chicago icons: Meigs Field, Lake Shore Drive, the Field Museum and the downtown courthouse named for the mayor's father.

These highly visible back-to-back service interruptions dramatically exposed the true depth of problems that by the summer of 2000. The company had to implement plans that went beyond immediate equipment upgrades and maintenance programs. To ensure that additional stress was not put on areas where improvements could not be accomplished for summer 2000, ComEd planning engineers joined efforts with the sales force to procure curtailable load. Surpassing its goal of more than 1200 MW, this targeted load-curtailment effort saved the immediate need for some upgrade projects. Ultimately, because of favorable weather and proactive load management, ComEd did not have to call for any system-wide curtailment programs during the summer of 2000.

To protect transformers that were not part of the 2000 improvement plan, additional monitoring was installed to identify potential degradation. The improved monitoring paid dividends. During 2000, newly installed transformer-monitoring systems sent alarms that triggered immediate and proactive inspections. The resulting maintenance was credited with saving imminent failure on no less than five occasions.

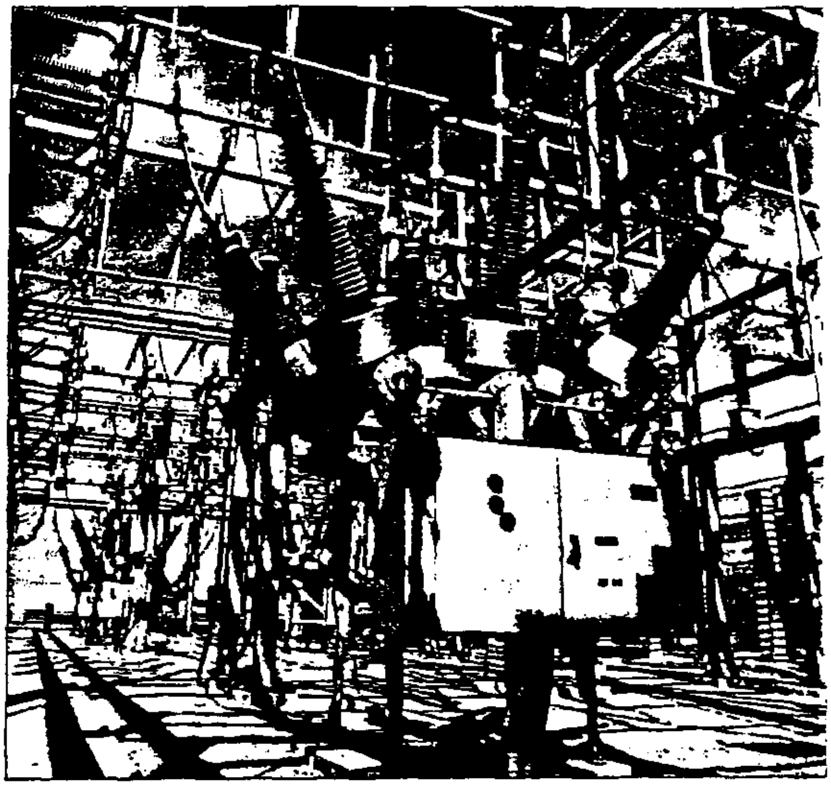


Fig. 4. At ComEd's Diversey Substation, this 138-kV switchgear was installed in eight months.

The Success

Manpower made a critical difference. ComEd employees worked an average of more than 60 hr a week, thus completing most of the distribution system and substation maintenance projects, along with smaller upgrades (Fig. 3). They were joined by more than 2100 contractors in a sustained partnership to complete the balance of the work, which included installing conduit, pulling cable, performing distribution feeder upgrades, completing substation projects, trimming trees, performing new business hookups, finishing overhead transmission maintenance repairs, and foundation and concrete work.

Other partnerships and alliances also were key to the turnaround. For example, GE/Harris provided turnkey projects for equipment, monitoring and relay upgrades while S&C Electric led a team that installed more than 100 pole top automated switches on the 34-kV system.

Of major concern was the growth of Chicago and the company's ability to support the energy needs of the city. The 2000 plan centered on six Chicago substations known as the "six-pack": Northwest, Diversey, Lakeview, Kingsbury/Ohio, Grand and Jefferson.

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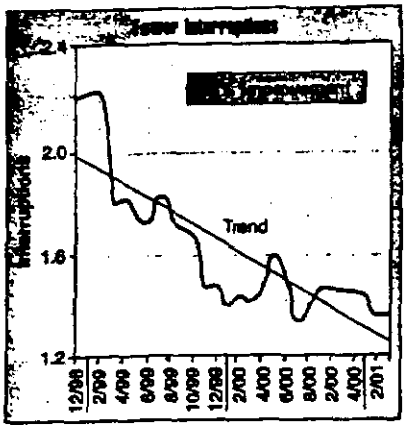

Fig. 5. ComEd initiatives have decreased the number of outages since December 1998.

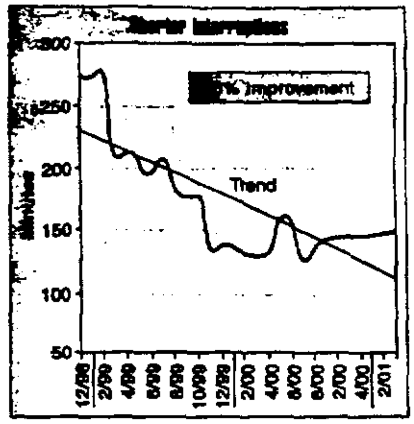

Fig. 6. Investment in infrastructure has resulted in lowered outage duration.

The most extensive modernization project accomplished was at the Northwest Substation, supplying power to more than 82,000 customers. An entire 12-kV substation was rebuilt over the top of the old one, two 75-MVA transformers were added and other upgrades were completed.

For Diversey, the challenge was even greater. An entirely new substation was erected on an urban site that had been commercial-use land as late as November 1999. Experts predicted construction would take two years to build the 138-/12-kV substation that would house four 50-MVA transformers, but ComEd didn't have two years. In the end, it was built and commissioned in about eight months, an almost unbelievable accomplishment of man, machine and management (Fig. 4).

The improvements on the remaining four of the Chicago six-pack included retiring the switchgear at the Lakeview substation and the conversion of feeders to 12 kV for better switching flexibility, making room for future substation work. A new GIS substation (Grand) was built to help load growth for the north end of the Loop business district. Finally, circuit breakers were refurbished and rebuilt at the Jefferson substation, the location that caused the severe 1999 outage in Chicago's growing South Loop.

ABB and Kenny Construction joined forces to complete the bulk of the Chicago six-pack projects by delivering a design, procurement and construction team able to fast track some complicated projects. Working through a minefield of equipment delivery lead times, permit approvals and ComEd workforce coordination, the team completed critical maintenance and other operations in some extremely confined urban areas.

While the fast-track nature of these Chicago six-pack projects is not the recommended course of action, the alliance team was able to deliver without significant outages or serious safety incidents. There were of course some trade-offs. The distribution system was at a greater risk because key elements were taken out of service for project cut-overs. Some customers experienced outages because of cable dig-ins, and cable failures caused more widely spread outages because many circuits were switched abnormally for construction purposes. Ultimately, risk mitigation and outage coordination were critical to the success of the projects.

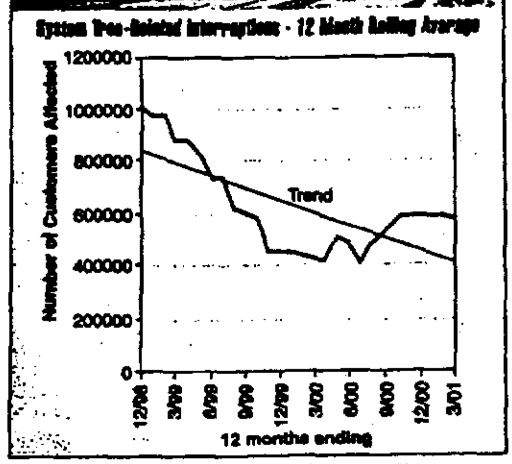

Fig. 7. Reduction of tree-related interruptions.

Comprehensive contingency plans were created to address other areas where high loads were projected. ComEd secured temporary and portable generators. The centralized Distribution Dispatch Center (DDC) made load forecasts and called for load switching and generator deployment on a day-by-day basis. During the summer of 2000, the DDC did an impressive job of proactively managing the load forecasts with switching steps, thus avoiding any widespread generator use.

ComEd again found itself under the gun when a sidewalk network vault roof collapsed in July 2000, triggering a fire and shutting down power to three high-rise buildings in Chicago's downtown. But in less than an hour, generators and emergency personnel were effectively deployed. In sharp contrast to summer 1999, city leaders joined business owners in acknowledging ComEd's quick and professional response. Chicago Environment Commissioner William Abolt hailed ComEd's response to the fire as substantially better than previous years. He told a Chicago newspaper, "We were really pleased that the first real test of the new emergency plan worked."

More than Equipment

For the T&D turnaround to succeed, John Rowe also demanded a complete overhaul of the company's communications efforts. In 1999, the mayor, the media and other critics described their acute frustration in getting information quickly and accurately. ComEd responded with a new plan to enhance communications with government leaders, the media and the Illinois Commerce Commission (ICC) to keep them informed about project plans, progress and outages. ComEd also established a timely communications process for informing the public when outages occur, what restoration efforts are underway and estimated times of when power will be restored.

The city of Chicago used Harza En-

Executive Commitment Remains Steadfast

David Helwig's mission was expanded in late 2000 to executive vice president of energy delivery operations, responsible for running the entire T&D organization. Today, David Helwig and ComEd Vice Chair Pamela Strobel are continuing efforts to lead one of the most comprehensive utility turnarounds ever. And, as summer 2001 approaches, it appears the combined efforts of new leadership, outside experts and the massive investment of resources and planning are paying off with substantial reductions in the frequency and duration of outages. Still, ComEd cannot promise a summer free of outages. "What ComEd does pledge," Strobel told the Chicago city council, "is fewer interruptions, faster restoration and better communications."

gineering as a third-party overseer to act on the city's behalf and provide objective expertise about the reasonableness and timeliness of ComEd's turnaround efforts. This innovative partnership enabled ComEd to help regain credibility with stakeholders throughout its service area. Today, ComEd provides detailed monthly updates to the ICC and the city about work progress and system performance, a practice of continuous, bare-knuckled scrutiny that is said to be the most extensive public reporting system of any electric utility in the nation.

Fewer, Faster, Better

ComEd continues to refine its organization and enter long-term alliance partnerships for engineering and construction support. Helwig's T&D plans for 2001 are as aggressive as for 2000. Today, the company has begun to climb out of the reliability hole. The critical atmosphere has somewhat dissipated. There is ample evidence that the upgrades, maintenance and new construction are showing the kind of measurable results Rowe demanded. The frequency of outages has decreased more than 38% since December 1998 (Fig. 5). The duration of outages has decreased more than 46% for the same period (Fig. 6).

Each time the company makes another deadline, fulfills another commitment or answers a customer's question, another step is taken out of the hole. More hard work is left but ComEd's efforts to date clearly demonstrate that key partnerships, innovative risk taking, and unyielding corporate focus are bringing about the successful rebuilding of both the power delivery system and the confidence of its customers.

Carl Segneri is the vice president of substations and transmission for ComEd Energy Delivery. In his 20 years at ComEd, Segneri has managed construction, engineering, transmission design and operational analysis. He was also regional distribution leader for the Chicago region, overseeing the inspection and repair of facilities identified as crucial to the proper functioning of the system. In addition to work in T&D, he performed engineering testing work at Dresden Nuclear Station and Will County and Collins fossil generating stations. Segneri holds the BSEE degree from the University of Notre Dame. He is a member of the IEEE.

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